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Benefits of Stochastic Scheduling for Power Systems with Significant Installed Wind Power

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***Abstract*— Wind energy on a power system alters the unit commitment and dispatch problem, as it adds a stochastic element due to the uncertainty of wind power forecasts. By explicitly taking into account the stochastic nature of wind power, it is expected that better schedules should be produced, thereby reducing costs on the system. This paper compares a stochastically optimised unit commitment and dispatch solution with a deterministically optimised solution. These are also compared to a case where perfect forecasting of wind and load is assumed. Using a planning model for the Irish system, it is shown that the schedules produced by stochastically optimising give a system cost less than that produced by deterministically optimising, if the same forecasts are used. The solution obtained when perfect forecasting is assumed is used as a base case for comparison. By examining unit operation, as well as interconnector usage, the reasons for the reduction in cost can be seen. It is also shown that using stochastic optimisation produces solutions which are better at meeting load and reserve targets.**

***Index Terms*— Wind power generation, Power system economics, Power generation dispatch, Unit Commitment, Wind Forecasting.**

I. Introduction

In the past decade, the number of installed wind turbines worldwide has increased dramatically. Some countries, e.g. Spain, Germany, Denmark, already produce a significant amount of their electricity from wind, while others, such as Ireland [1], [2], Great Britain [3], and certain US states, have plans to provide large amounts of their electrical energy requirements from wind power. This wind power will have a significant impact on the operation of power systems on a number of time frames, from seconds and minutes (regulation and frequency issues), to hours and days (unit commitment and dispatch), to years (transmission network planning). In this paper, the impact of wind power on day ahead and hourly planning of the system is examined - that is, the changes in unit commitment and dispatch due to increasing levels of installed wind power. The aim of unit commitment is to create a generation schedule to meet demand at lowest cost, typically over a period of 24 to 36 hours ahead. Current methods used (i.e. without significant installed wind) are well established, and it is usually treated as a deterministic problem as in [4]. Adding wind power to the system introduces a stochastic element to this problem, as there is an uncertainty associated with wind power forecasting [5]. This means that, to reduce the risk of times when wind power is not as high as forecast and there is not enough conventional generation to meet demand, extra reserve needs to be carried on the system [6]. This may mean more units online, and therefore this reserve should be minimised to reduce costs.

To take into account the uncertainty of wind power forecasting when minimising expected costs, multiple scenarios of wind and load can be used. This way, the stochastic nature of wind power is included when committing units, and more robust schedules are provided which can handle the uncertainty of the wind power forecasts. The WILMAR project [7] used a stochastic model to analyse the impact of wind power integration for liberalized electricity markets. This uses a rolling planning type of operation, whereby the forecasted wind and demand is updated before every optimisation. Because more robust schedules are provided when stochastic wind and load are examined, the total expected costs of operating the system should be lower than if a purely deterministic approach was used. It should be noted that the model used in this study is a planning tool and, as such, does not take into account a forecast error in the period from one rolling optimisation to the next, but rather assumes perfect forecasting in this period, and introduces the stochastic properties of wind for periods after the next optimisation. It also uses an hourly time resolution, whereby wind and load data is given once an hour, and therefore does not examine what happens intra-hour. This means the planning costs calculated by WILMAR are, on average, an underestimate of what the actual system operating costs would be. In this paper, expected costs refer to the costs calculated by the model, and these differ from actual costs as they do not take into account error at all times.

This paper examines the differences that can be seen when stochastic optimisation is used instead of deterministic optimisation when planning the system. For comparison, these are also compared to a case where wind and load forecasting is perfect, i.e. it does not have any error associated with it. The total expected costs for a year of data, as well as unit operation, interconnector usage, and expected amount of hours when load and/or reserve targets are not met, are examined. Section II gives an overview of the methodology used. Section III describes a possible portfolio for Irish system in 2020, which the model is applied to. The results from this simulation are discussed in Section IV, and conclusions and further work are examined Section V.

This work has been conducted in the Electricity Research Centre, University College Dublin which is supported by Electricity Supply Board (ESB) Networks, ESB Power Generation, ESB National Grid, Commission for Energy Regulation, Cylon, Airtricity and Bord na Mona.

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II. WILMAR MODEL

This study uses the WILMAR model, a stochastic model to analyze integration of wind power. Below is a summary of the model, which is fully described in the workstream 2B final report for the All Island Grid Study [8].

The main functionality of WILMAR is in the Scenario Tree Tool (STT) and the Scheduling Model. These are used with databases and other code to provide links between the two models and input and output from and to the user. The STT is used to generate the stochastic inputs required - i.e. the load, the wind power forecasts, and the demand for replacement reserve, which is based on expected wind and load. Each scenario is also given a probability of occurrence. These are represented on a scenario tree, as shown in Figure 1. Each scenario has an expected wind and demand, and a target for replacement reserve. Here, replacement reserve is calculated based on a look up table using the method described in [9]. Forced and scheduled outages are also provided by the STT. The STT uses, as input, historical wind and load data, plant outage data, and the assumed accuracy of wind forecasting.

The scheduling model used here is a mixed integer, stochastic optimisation model [10], as used in [8]. Therefore it is a more sophisticated version of the model than that described in [7] and [11], which does not use mixed integer programming. The decision variables are whether a unit is online or offline, and whether a unit that is offline should be started up. As well as the inputs from the STT, the scheduling model has data for the units on the system, i.e. startup time, minimum up and down time, heat rates, ramp rates, startup and fuel costs. Using an hourly time resolution, it minimises the expected operating costs over all scenarios, without knowledge of which will be closest to the actual system operation, only the probability of the scenario occurring. The cost function being minimised is made up of fuel costs, startup costs, emission costs and the value of imports or exports on the interconnector. Using multiple scenarios means the solution will be robust enough to cover all the scenarios, as well as any values of wind and load between these scenarios. The model uses multi-stage recursion with rolling planning - as more precise wind and load forecasts become available, the unit commitment and dispatch decisions are re-optimised from the current state of the system, taking into account any temporal constraints on unit commitment. The idea of rolling planning, as well as an illustration of the scenario trees, is shown in Figure 1.

The version of WILMAR in [8] used a three hour time step as shown, meaning that, for every 24 hours, there is 8 planning periods. Rolling planning proceeds as follows: The first rolling planning period, at 12am on day one, covers 36 hours, until the end of the following day. Subsequent planning periods take this dispatch into account when rescheduling for updated wind and load forecasts. The expected commitment of the units - on or off, as well as the level of production, can therefore be altered to account for changes from one planning period to the next. The units providing reserve also have to be on if they have a startup time of less than one hour - i.e. if a unit has to provide reserve in four hours and has a two hour startup time, it must be turned on in hour two to provide this reserve. The length of the forecast horizon which the system is optimised over is reduced for subsequent planning periods, as the optimisation period always ends at the end of the second day. The unit schedules for the first three hours in every rolling planning period are then put together to give a dispatch schedule for the whole year.

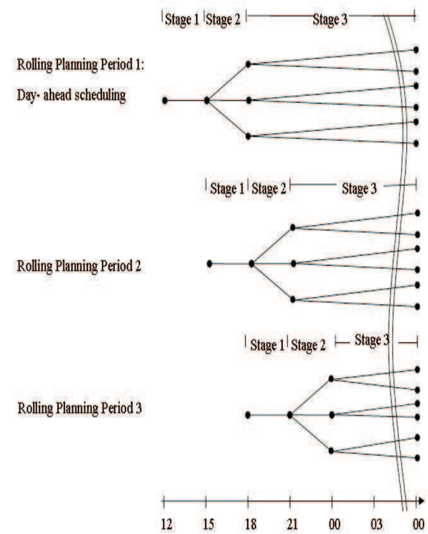

Fig. 1. 3 hour rolling planning with scenario trees

Note that hourly time steps are used in this study - this plot is for illustrative purposes. The first stage of the tree is the deterministic stage, which assumes perfect forecasting. As mentioned earlier, this means that the tool cannot be taken as an operational tool. The next stage of the scenario tree splits into three scenarios for the next three hours, while the final stage from six hours until the end of the following day, has six scenarios.More information about the WILMAR model and stochastic optimisation of wind power can be found in [7] and [11].

In this study, rolling, as described above, is carried out every hour. This should mean that the most accurate possible schedules are produced, which should be closest to the actual expected operation. This is due to the fact that, as the rolling is done more often, the length of the perfect forecast stage is reduced, and therefore more of the uncertainty of wind is taken into account. If the planning was carried out every three hours, the underestimation of the cost would be larger than when it is done every hour.

III. APPLICATION OF MODEL TO IRISH ELECTRICITY SYSTEM

The model described in the previous section was applied to the Irish power system, to analyze effects of stochastic wind power production. The configuration of this system is based on one of the scenarios examined in [12], part of the All Island Grid Study, which was carried out to analyse the development of renewable energy on the Irish grid. This particular portfolio

Type of unit	Capacity (MW)	Fuel (€ / GJ)
Coal	1257	1.75
Midmerit Gas	1646	6.46
Baseload Gas	4114	5.91
Peat	345	3.71
Base RE	360	2.78
Hydro	216	-
Pumped Storage	292	-
Tidal	200	-
Wind Power	6000	-

TABLE I

TYPES OF UNIT IN PLANT PORTFOLIO USED IN STUDY

has 6000MW of installed wind capacity, producing 18.4TWh of wind (which corresponds to approximately 42% of total energy demand). The total installed capacity on the system, excluding wind, is approximately 8100MW. This is made up of the units described in Table I. Note that two types of gas plant are included - mid merit gas, i.e. Open Cycle Gas Turbines (OCGT), which are peaking and mid merit plant (some of which can also use diesel), and base loaded gas, i.e. Combined Cycle Gas Turbines (CCGT), which are base loaded plant. Table I also shows the fuel prices used for the various conventional plants, to give an indication of where that type of unit is on the merit order of the system. The price given for the gas units is an average of the different prices used at different periods of the year.

The system examined has a peak demand of approximately 9600MW, and a minimum demand of 3500MW. There is 1000MW of interconnection to Great Britain assumed. Currently, there is 500MW of interconnection in place, with a further 500MW planned. The British electricity system is modelled by grouping together similar units in blocks, so there are large blocks for nuclear, coal, CCGT, etc. Britain is treated deterministically in this study. While this means that the prices for Britain will not be exactly as they should be if stochastic wind was used, it was decided that it would not alter the effects significantly, as the amount of wind installed in Britain in this study would be relatively small compared to overall system size - around 12% of energy in the year examined. The model is run for 3 different cases using the above portfolio, as described in the previous section - deterministic wind and load with perfect forecasting (hereafter referred to as perfect forecasting case), stochastically optimised wind and load, and deterministic forecasts for wind and load with imperfect forecasting.

The model was run for a year of data, also taken from [12]. Using a computer with an Intel 3GhZ processor with 3GB of RAM, the model took approximately 11 days to solve the stochastic case with hourly rolling, 3 days to solve the deterministic with imperfect forecasting, and 1 day for the perfect forecasting case. The model was solved using the Cplex mixed integer solver with a duality gap of 4% from the objective function, as it was found that, for higher precision, the calculation time proved much longer.

IV. RESULTS AND DISCUSSION

This section examines the results obtained when the model described above is run with data for the Irish system in 2020 for the following three cases: Firstly, perfect forecasting of wind is assumed in all periods, and a deterministic version of WILMAR is used, where there is only one scenario in each stage of the scenario tree. This will show the benefits of achieving perfect forecasting of wind power when operating the system, and the expected operation of units on the system if this could be achieved. This can be seen as the ideal, though unrealistic, case which would have lead to lowest possible costs for the particular system. Then, the model is optimised stochastically, as described in Section II. Finally, the deterministic version of the model is adapted so that the wind and demand forecasts change for every planning period. This is done by taking the expected value of the stochastic forecast for each planning period, which gives one expected value for each period of the forecast, as opposed to multiple values in the stochastic case. The first stage will still be assumed to have perfect forecasting, as in the stochastic case, but subsequent stages will have single forecasted values for wind, demand, and replacement reserve, based on the weighted average of the stochastic forecasts. Therefore, it can be solved similar to the perfect forecasting case, however, whereas the forecasts don't change from one rolling period to the next when using perfect forecasting, each rolling loop in the deterministic with error case is updated with a new forecast.

From the above three cases, the benefits of using stochastic optimisation when scheduling a system with large amounts of wind power can be seen. By comparing the case with perfect forecasting with the other two cases, the impact of wind uncertainty can be seen. Then, by comparing the stochastic solution with the solution for the deterministic forecasts with error, the benefits of using stochastic optimisation can be seen. Note that it will not show exactly the value of using stochastic optimisation, as defined in [13]. This would not be possible, as it would require one expected value and one realised value over the full time period, which is not available in this multi-stage recursive approach. However, it would be expected to show the cost reductions that would be realised if stochastic optimisation, instead of deterministic, was used with rolling planning when scheduling the system.

The results obtained are examined in a number of ways: firstly, the costs are examined, to show the change in expected costs when stochastic optimisation is used instead of deterministic, and also to show the expected benefit of perfect forecasting. Then, the changes in the operation of units on the system are examined, to show how units operate differently as uncertainty is introduced, and then to show how the way this uncertainty is treated changes their operation. The usage of the interconnector to Great Britain is examined, and the expected reliability of the system - i.e. the number of hours it is expected to meet load and reserve targets.

A. Impact of optimisation method on costs

The change in expected total system costs for the stochastic and deterministic cases versus the base case can be seen in

Figure 2. Here, total costs means the total expected operating (fuel) costs, as well as start up costs, emission costs and the costs, if any, to provide reserve - this last cost is due to extra units having to startup to provide reserve. The total costs for Great Britain and Ireland have to be examined, as the interconnector operation can also change. However, as Great Britain is treated deterministically with perfect forecasting, the changes in interconnector usage will only be due to the change in the way demand and wind forecasts are managed in the Irish system. As the total costs for Great Britain are an order of magnitude greater than total costs for Ireland, the change in total costs here (i.e. two areas) is given as a percentage of the Irish system costs. The total cost for the perfect forecasting base case is €13484m, of which €1491m occurs in Ireland.

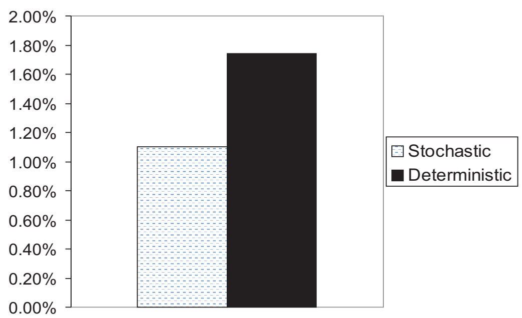

Fig. 2. Increase in costs versus perfect forecasting case for stochastic and deterministic cases

As expected, that the lowest total costs are for the case with perfect forecasting. Schedules produced when using perfect forecasting, although unrealistic as no extra reserve is needed and wind does exactly as expected, are the least cost, as they assume wind and load are known perfectly in advance. Therefore, an increase of costs of 1.1% - 1.7 % shows the value of achieving perfect forecasting. Then, the benefit of using stochastic optimisation instead of deterministic can be seen to be about 0.6% of expected costs of the Irish system. While this may seem small, when it is considered that the best improvement that can be made is to have perfect forecasting, i.e. improving the costs of deterministic optimisation by 1.7%, a change of 0.6% is almost one-third of the total possible reduction in costs. It is important to note that these two methods use the same inputs for wind and load forecasts, but just change the way they use them - by using the stochastic inputs explicitly in the optimisation, costs can be reduced compared to when these inputs are averaged. While a reduction in costs could also be achieved by making deterministic forecasts more accurate, it is unlikely that the cost reduction achieved by improving forecasts would match the reduction made when using stochastic optimisation without major improvements in forecast accuracy.

B. Changes in scheduling of system

To examine reasons for the change in costs as seen in Figure 2, the planned operation of the power system was examined over the year. From this, the effect that perfect forecasting has on the system, as well as the effect that using stochastic instead of deterministic optimisation, can be seen. The change in the expected reliability of the system, that is the ability to meet load and reserve targets, is also examined.

1) Operation of units on Irish system and usage of interconnector: As shown earlier in Table I, the system examined had different types of units, which would be placed differently on the merit order. As wind, when blowing, must be accepted, it is expected that the greatest change in unit operation will be in the mid merit and peaking gas plants, described as mid merit gas in Table I. The units closer to being base loaded would be expected to start up less, as they will be on most of the time. Figure 3 shows the number of starts, by fuel type, for the units in the system. The number of starts for the perfect forecasting base case is as follows: Baseload Gas - 142, Coal - 184, Peat - 328, Mid Merit Gas - 4425, Total - 5079.

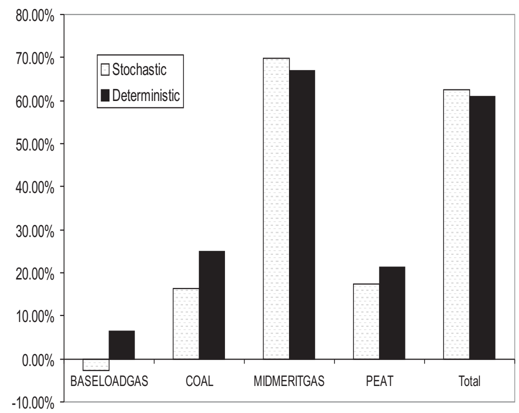

Fig. 3. Increase in unit startups versus perfect forecasting case for stochastic and deterministic cases

As can be seen Figure 3, the total number of starts increases dramatically when comparing perfect forecasting optimisation to the cases where the forecast is imperfect, by approximately 60%. This can be explained in the stochastic case by the fact that a range of future values are being optimised for, and so more units, especially mid merit units, may be planned to start up at a relatively short space of time, depending on which scenario is closest to the actual wind and load. As the future wind and load is not certain, it is not worth putting on larger, slower base loaded plant, when a smaller mid merit unit could be a better option, depending on the future outcomes. However, with the deterministic optimisation case, only one future outcome is planned for, which is the reason that, while the startups increase compared to the perfect forecasting case, there are slightly less in this case than in the stochastic case. When only one future outcome is planned for, it may, on certain occasions, seem more optimal to use a base loaded plant, which will take longer starting up and stay online longer, than a mid merit unit which may or may not start up depending on which scenario occurs, as is the case with stochastic optimisation. Therefore, the coal and peat plants are started more in the deterministic case, while mid merit is started slightly more in the stochastic case. As base loaded plants are more expensive to start up, if they are started and shut down more frequently than expected, they will cause the system costs to rise, and this is one reason why the deterministic optimisation is more expensive.

To examine the effect that this change in start ups of units has on the total production by them, the production by unit type was examined and is shown in Figure 4. The values for the base case are as follows: Baseload Gas - 18851GWh, Coal - 6615GWh, Peat 193GWh, Mid Merit Gas - 517GWh, Storage - 528GWh, Net Import - 3.06GWh.

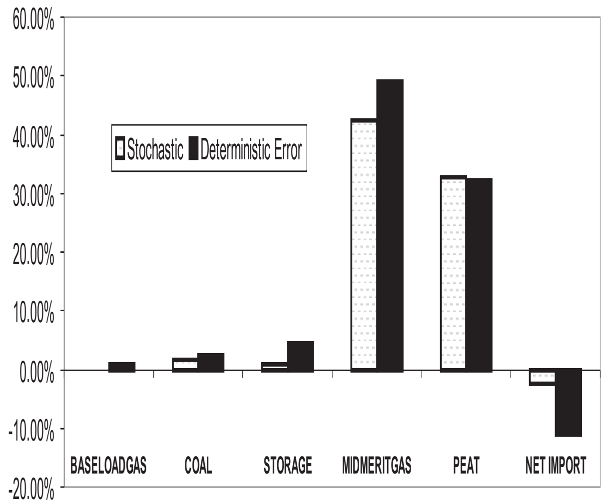

Fig. 4. Change in production versus perfect forecasting case for stochastic and deterministic cases

As can be seen from this table, there is very little change in the production from base loaded gas, and coal units, less than 2%. However, mid merit gas and peat, which, while base loaded is closest to being mid merit, increase significantly when a forecast error is introduced. While peat produces the same whether the system is optimised deterministically or stochastically, the mid merit gas produces more when the system is optimised deterministically, about 6% more. This means that, even though the units are started less, when they are online they produce more. This would be expected as the interconnector is not used as much, and also because the deterministic case is more likely to have to call on the mid merit units to cover for a shortfall in scheduled generation at a short space of time, whereas the stochastic optimisation will use mid merit to cover for when the future scenarios are very different, and will therefore be using them more to make up a smaller amount of the demand. The pumped storage units on the system can also be seen to be used more in the deterministic optimisation case, as these are used when the load cannot be met in other ways.

It is also instructive to look at the change of operation of the British system due to the way the Irish system is being optimised. This can be seen by looking at the total net import into Ireland. As can be seen in Figure 4, the interconnector is used most when the future wind and load is better known. The case with perfect forecasting uses the interconnector the most, as the schedules produced are more likely to not have extra units turned on, and therefore can take full advantage of the cheaper prices in Britain. The stochastic case will, on average, plan for scenarios closer to the actual value than the one scenario planned for in the deterministic case. This means that it will end up having less spare capacity on units that do not need to be on and will therefore import more, and it will also stick to its schedule more, which will mean it can avail of the interconnector more often.

	Average Supply	Average Demand
Perfect	544	540
Stochastic	574	557
Deterministic	569	557

TABLE II

REPLACEMENT RESERVE SUPPLY AND DEMAND

	Load not met (hrs)	Primary (hrs)	Replacement (hrs)
Perfect	1	4	602
Stochastic	1	4	618
Deterministic	2	9	829

TABLE III

RELIABILITY OF SYSTEM FOR THREE CASES EXAMINED

2) Reserve and reliability of system: Another reason that the case with perfect forecasting is less expensive is the fact that, due to having perfect forecasting, no replacement reserve is needed for wind. Replacement reserve is reserve acting in timescales larger than 15 minutes. Primary reserve, which is less than 15 minutes, is not greatly affected by the addition of wind power, as the variability of wind power is seen more with time scales of 15 minutes and longer. The replacement reserve targets, and the supplied reserve for the different cases, are shown in Table II. This also shows the fact that the reserve target for both optimisations with imperfect forecasting is the same, as expected. As can be seen, the case with stochastic optimisation provides more reserve on average, as it has a more robust plan to meet any possible future scenarios.

The three cases are also compared to each other with regard to reliability. This is the amount of hours per year that the system fails to meet demand, or reserve targets. Note that this is different from the expected reliability that would be used to calculate the amount of reserve needed, and given as, for example Loss of Load Expectation, as it is only based on values for one particular year's worth of data, and would could not be used to give the expected reliability of the system. Instead, this is the actual amount of hours that the load could not be met. However, it does give an indication of what would happen if the system is planned in the different ways, i.e. stochastically, deterministically or with perfect forecasting. The results obtained are shown in Table III.

Here, primary refers to primary reserve not met, while replacement is replacement reserve not met. It can be seen that the amount of hours the system cannot meet load is quite small. This is expected, as the portfolios produced for the All Island Grid Study in [12] were designed to be reliable, with a low amount of lost load per year. With regard to reserve, it can be seen that the stochastic optimisation gives results very similar to a case with perfect forecasting. This shows that the schedules produced with this method are more robust, and can handle changes in the wind and load forecasts better than when the system is optimised deterministically. Therefore, even in a system designed to be reliable, it can be seen that the way it is operated changes the reliability of the system.

V. Further Discussion and Future Work

From the results given in the previous section, it is clear that, when dealing with the uncertainties of wind and load, it is better to use multiple scenarios and do a stochastic optimisation rather than deterministically optimising over one scenario. Obviously, this assumes that producing multiple forecasts, and the probability of each one occurring, is possible, as used here. It can be seen that, while stochastically optimising produces more startups, it is with mid merit units, which are cheaper to start. However, these are more expensive to run, and stochastically optimising actually means these units are planned to produce less electricity - i.e. they start more, and are used more as peaking units, whereas when the system is deterministically optimised they are used in the mid merit range more, and base loaded units are also being used more in the mid merit range, leading to a cost increase.

It is also seen that the interconnector is used more when more reliable information is known about wind and load - whether that is that the wind and load are perfectly forecast, or a possible range of values are known. By optimising stochastically, more reserve is able to be provided, and this leads to the fact that, in the particular year examined, the stochastic optimisation and the perfect forecast case gave similar results for the amount of times reserve targets could not be met, whereas the deterministic optimisation led to more frequent shortfalls in reserve. As stated in the introduction, it should be noted that these are results for the planning of the system, and as such cannot be treated as exactly what would happen in actuality. Here, the costs are, on average, underestimated. However, by looking at the change between the perfect forecasting case and the other cases, it can be surmised that mid merit units would be used more, the reserve needed would increase,the net import on the interconnector would decrease, and therefore the costs would go up. However, it can be seen that optimising stochastically reduces the increase in cost, while also improving the reliability, and utilising base loaded plant more.

Further work that could be done on this type of study would include examining the plant mix on the system - i.e. if there was less mid merit units, and how that effects the unit commitment. In this study, there was no error assumed in the hours between commitments, as described earlier. This obviously leads to less realistic results, so more work could involve including this error, as well as examining the effect that intra hour changes have on the system. Further work would also involve the effect that rolling the system every hour, as done here, has on the actual costs - as the system is rolled more often, cycling would increase, and therefore push system costs up.

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